Charles W. Byrer
Project Manager/Geologist, Fuels Resources Division
Office of Project Management

Coalbed Methane Gas
From "Miner's Curse" to Valuable Resource

The coal industry used to look disdainfully at the natural gas that permeates most coal beds, regarding it only as a dangerous waste product. Indeed, coalbed gas was nicknamed the "miner's curse," because it escapes from coal seams and can ignite explosively.

The miner's curse is now an energy opportunity—and an environmental problem.

Gas explosions have killed thousands of miners over the years. The worst U.S. mine disaster of the twentieth century occurred in the Federal Energy Technology Center's (FETC's) own back yard—361 miners perished in a gas explosion at Monongah, West Virginia, in 1907.

We've come a long way since then. Natural gas in coal mines will always be a hazard, but the risk of explosion has been greatly mitigated by safety regulations, sensitive gas detectors, and mine ventilation with powerful fans that exhaust the gas into the atmosphere.

And therein lies both an opportunity and a possible risk of global climate change. Although venting

gas into the atmosphere has reduced underground explosions to infrequent events, it also discards potentially valuable fuel and adds methane—the chief component of natural gas, and a potent greenhouse gas—to the atmosphere. Thus, the large volumes vented by mines represent both an economic loss and an environmental challenge.

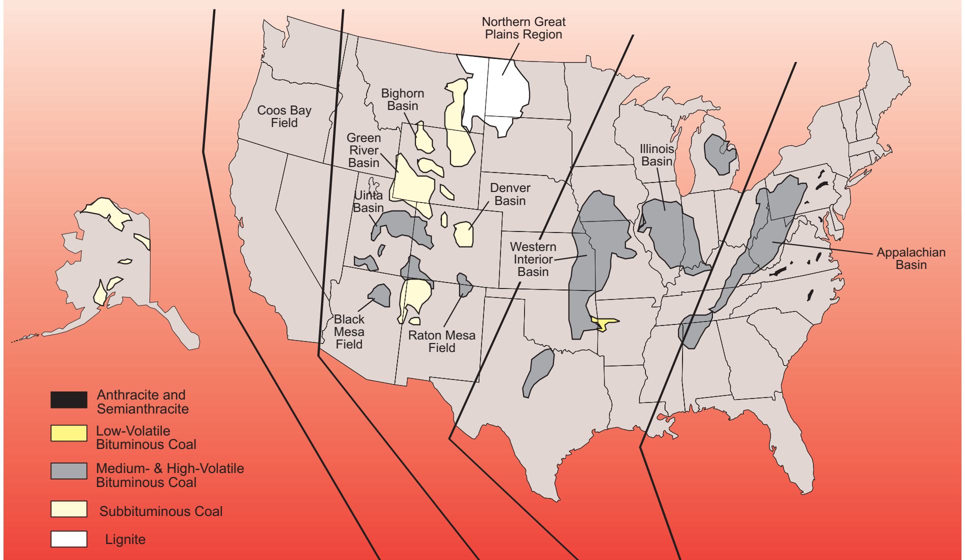
In 1990, up to 300 billion cubic feet of methane were vented from U.S. coal mines (mostly underground operations). This is 15 percent of all global methane emissions from coal mining, and nearly 10 percent of all methane released into the atmosphere by humankind.

Furthermore, methane's greenhouse gas potential is many times greater than CO_2's, so its release during coal mining and processing is a concern. Currently, the atmospheric methane concentration is a lesser problem than CO_2, simply because methane is much scarcer in the atmosphere, with only 1/200th the concentration of CO_2. But this is changing: the methane percentage is slowly increasing worldwide, at a faster rate than the CO_2 percentage. The U.S. Geological Survey is forecasting methane to surpass CO_2 as the dominant greenhouse gas in the second half of the 21st century—if its concentration continues to grow at the present rate.

Bountiful Methane in Most Coal Beds

As coal forms slowly from decaying plants over millions of years, methane forms along with it. Thus, most coal beds are permeated with methane, so much so that a cubic foot of coal can contain six or seven times the methane that exists in a cubic foot

Estimated Coal Resources in the U.S.—90% Considered Unminable



Total Coal to 6000 Feet	2030	100	3260	620	350	Total = 6360
Mineable Reserves	12	2	200	110	110	Total = 430
Unmineable Reserves	640	20	920	140	80	Total = 1800

of a conventional sandstone gas reservoir. However, the methane content in coal is highly variable, varying widely over short distances (a few hundred feet, for example). The higher grades of coal are richer in gas, and deeper coal beds are "gassier" (because they are able to vent less easily to the atmosphere).

The gas often occurs in concentrated pockets as well, creating a major mining hazard. When mining breaks open these pockets, or when coal is pulverized during mining and processing, methane is released into the mine and the atmosphere. In addition to ventilating the operating areas in mines, methane often is removed from the virgin coal in advance of mining by drilling extraction wells into the coal seam and venting the gas into the atmosphere. However, greenhouse gas regulations may limit venting of all types.

Estimates are that 400 to 700 trillion cubic feet (Tcf) of methane exist in U.S. coal beds. Although only 90 to 100 Tcf may be economically recoverable with current technology, this equates to a 4-year supply of natural gas for our nation. More realistically, it can be viewed as a 25-year supply for one sixth of our current annual need. And the world coalbed methane resource spans all populated continents and is estimated at 4,000 to 7,500 Tcf, so it is an extremely large potential energy resource.

The energy (Btu's) in coalbed methane can amount to several percent of the energy in the coal itself. The amount varies widely, from little gas in a ton of coal, up to 5,000 cubic feet. As a general example, burning a ton of bituminous coal can release 21 to 30 million Btu of heat energy, depending on the coal's rank. The methane within that ton of coal—typically 250 to 500 cubic feet of the gas—can provide 250,000 to 500,000 Btu when burned. In many cases, this can make the gas worth recovering as a fuel.

Coalbed Methane: Already a Commercial Success

Coalbed methane (CBM) has strong economic potential. It can be used to generate electricity, either at mine sites or by pipelining it to commercial utilities. It can be cofired with coal to reduce SO_X and NO_X emissions. It can fuel gas turbines or fuel cells to generate power. At mines, it can fire drying units that remove moisture from washed coal. And it can be pipelined for utility and industrial use. Some of this potential already is being realized.

During the 1930s, the Big Run gas field in northern West Virginia began producing coalbed gas from the thick Pittsburgh coal seam and continues producing to this day, demonstrating a common characteristic of coalbed wells: they tend to produce much longer than conventional reservoirs. By the late 1970s, some CBM was being produced commercially from coal beds in Alabama. In northern New Mexico, 40 billion cubic feet of CBM have been produced from 1,700 wells. Self-supporting CBM projects also exist in Colorado and Virginia. Currently, pipeline-quality coal mine methane is being sold to distribution systems in the Appalachian coal basin.

Today, the annual U.S. demand for natural gas is about 21 Tcf, with more than 1 Tcf being produced from coal mines and unmined coal beds, or nearly 5 percent—quite a success story for what was once a waste product and “miner’s curse.” And this production is projected to increase as demand rises, as technology improves, and as mining companies cooperate with gas producers to utilize—and maybe turn a profit from—gas that it is desirable to remove from the coal and sequester from the atmosphere.

Coal Mine Methane Pros and Cons

Coal mines can simultaneously produce methane and consume it by generating electricity on site. This on-site capability is valuable because the mining operation needs electrical power to operate machinery and for ventilation fans, coal cleaning plants, coal dryers to remove moisture, and other surface facilities. An underground mine’s vent fans alone can consume 75 percent of the total electricity used at the site. Power generated from mine gas also can be fed to the grid that supplies electricity to the mine, selling the energy back to the power supplier. Such uses of mine gas can more than offset its cost of recovery.

FETC has sponsored several field tests to recover coal mine methane and use it to generate power on site. Use of mine gas to fuel combustion engines and gas turbines has been demonstrated. Also promising is the use of mine gas in fuel cells.

One problem with coal mine methane is that its quality varies, particularly if the gas has been mixed with ventilation air in an operating mine. Pipeline-grade natural gas must be at least 97-percent pure methane, so lower-quality mine gas must be upgraded for distribution by removing water and other gases (CO_2, nitrogen, and oxygen).

The gassiest U.S. mines are in the Appalachian coal basin, which stretches from Alabama to Pennsylvania. Some of these mines are recovering and using mine gas. The 1992 methane recovery from U.S. underground coal mines (not including methane tapped from unmined coal seams) was about 25 billion cubic feet.

Commercial successes in this basin include a large Alabama longwall mine that is selling over 40 million cubic feet of pipeline-quality mine gas per day. The largest coal mine methane project in the country is

In northern New Mexico, 40 billion cubic feet of CBM have been produced from 1,700 wells.

in western Virginia, where pipeline-quality mine gas is being sold to a utility.

Recovering methane from operating mines is not all roses. The coal industry has long seen methane as a problem, not a resource, so a different viewpoint is required. Coal beds are far more complex geologically than conventional natural gas reservoirs. Mine gas recovery adds cost in equipment, work force, services, and meeting additional regulatory requirements. Not all mine gas is of pipeline quality. There can be questions of gas ownership and royalty rights. And there is the question of unproven economics of recovery.

But improved technology for recovery, combined with potential utilization and the need to meet future greenhouse gas regulations are nudging CBM toward wider commercial success.

Profit Opportunities in Unminable Coal

Today, coal is mined from thick beds with high-volume mining machinery that feeds a virtual conveyor of road-rail-river transportation to our nation's power plants. This high-volume strategy holds down the cost of coal and electricity, but it also renders about 90 percent of U.S. coal "unminable," meaning that it is unprofitable to mine with present technology. It is unprofitable because of coal-seam thinness, poor or inconsistent quality of the coal, or difficult mining conditions.

But this unminable coal represents a vast, largely untapped *methane* resource. As demand for natural gas increases, coalbed methane is growing more attractive as a fuel. More than 16,000 communities, many in the South, lie above coal seams that could produce methane. This fuel could be delivered locally, reducing the need for interstate gas transportation hundreds of miles from distant gas fields.

CBM is gaining strong interest nationally, but the Southeast U.S. is a particularly promising market, because of its large gas demand and the Appalachian basin's many gassy coal seams. Here we have a large resource near major markets, all lying within an established pipeline infrastructure. CBM is potentially capable of making seven states at least partially self-sufficient in gas supply—Kentucky, Maryland, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. In West Virginia's case, the state could be 100 percent self-sufficient, satisfying its entire natural gas demand from its own coal beds.

Furthermore, CBM can be locally competitive with conventionally produced pipeline gas. In addition to recovering methane from unminable coal beds, the gas can be harvested from active underground mines as well.

FETC's Pioneering Research in Coalbed Methane

Under the President's Climate Change Action Plan, the Department of Energy is responsible for identifying barriers to developing the resource and methods for its recovery and use. For two decades, FETC has been the lead government laboratory for partnering with the coal, gas, and utility industries to develop and implement the technology for capturing and utilizing coalbed methane, and in sequestering it from the atmosphere.

FETC began extensive CBM research, development, and demonstration in 1977, when government and industry began to look at alternatives to conventional gas sources (mostly sandstone reservoirs). A federal tax credit for CBM production expanded drilling in the mid-1980s, and promoted development of new drilling technology.

FETC and its research partners have come a long way toward developing the CBM resource. FETC has assessed the resource in 16 of the country's 26 major coal basins, and established geologic areas where production is favorable; established guidelines for efficient recovery, and determined that efficiency is greater in horizontal wells; assessed the potential of gas production associated with longwall mining in the Appalachian basin; established valuable partnerships with industry, academia, utilities, and municipalities; and greatly expanded the knowledge base for CBM development.

Convergence at the Millennium: Coalbed Methane and CO_2 Sequestration

International economic, environmental, and technological drivers are converging at the start of the new millennium to make us consider CBM recovery and CO_2 sequestration together. The idea is to sequester CO_2 in unmined coal beds, which have an enormous capacity for CO_2, while at the same time recovering the methane already in them. The CO_2 would be injected via wells drilled into the coal, and pressure from the CO_2 would drive the methane out of the coal through the wells to the surface, where it would be collected. This two-birds-with-one-stone idea is feasible because coal stores CO_2 in twice the volume that it stores methane. The net result would be less CO_2 in the atmosphere, no significant new methane added to the atmosphere, and recovery of methane to help pay for the process.

What about the logistics and cost of this CBM/CO_2 strategy? Most U.S. power plants are within 3 to 5 miles of a coal bed (not necessarily a suitable one, of course). For a plant near a gassy coal bed (or multiple beds, for coal often occurs in multiple seams, like a layer cake), pipeline length would be minimal to convey CO_2 from the plant into the coal, and to pipe recovered methane back to the plant. DOE considers this approach an important option in support of the Climate Change Action Plan and the Kyoto Protocol.

Coalbed Methane's Future

Today, industry and academic research interest is running high because the methane recovery/CO_2 sequestration concept could be a least-cost option in the energy-economy-environment trilemma. But much work lies ahead. Candidate coal beds must be targeted, and the potential methane resource must be determined for each bed. The feasibility of drilling CO_2 injection wells and methane recovery wells must be determined for each targeted bed. All environmental factors must be considered, including surface land use and water quality. Cost is a paramount consideration. And timeframes must be established.

Alberta CBM/CO_2 Project

A consortium of Canadian and U.S. organizations will develop new technology to reduce greenhouse gas emissions. The technology also promises to enhance production from Canada's large CBM reserves. This work, led by the Alberta Research Council and supported by DOE, Environment Canada, and industry partners, is attracting international interest. It is one of several promising environmental projects recognized at the Kyoto conference in 1997.

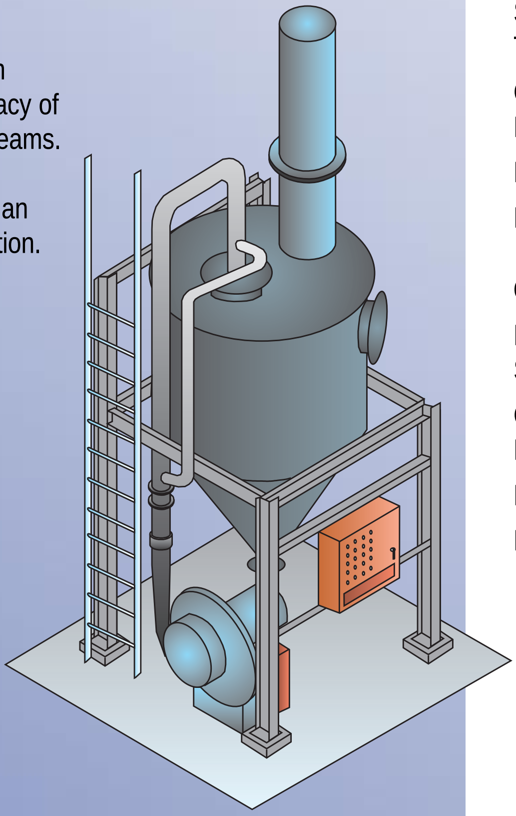
Many of Alberta's coal beds are rich in methane, making this an ideal testing ground to develop new technology. The CBM/CO_2 project is testing CO_2 injection into the province's vast, deep unminable coal beds. This will set the stage for validation of a system to reduce CO_2 emissions while increasing methane production. Results of this field test will be extrapolated to coal beds in the United States and other countries.

Another Success: Brine Management

Attractive though it is, methane from coal beds comes with an environmental price. Coal beds store considerable water in their pores and fractures. Pressure from this water confines the methane within the coal. To free the methane, the coal must be "dewatered" by pumping the water to the surface. Methane wells drilled into coal beds produce exceptionally large volumes of water, averaging more than 13 times the water produced from a conventional gas well. Furthermore, the water is often brine (salty), especially early in production. This creates a major problem of water disposal, for brine is toxic to most plants and freshwater fish. In most cases, the water must be reinjected underground—if permissible at the location. Before our vast resource can be fully developed, environmentally acceptable technologies for brine management need to be adopted.

From this challenge is emerging another success story: a FETC research partner is demonstrating the use of CBM to partially fuel the processing of saline minewater into fresh water for public supply and agriculture, while recovering dried salts from the brine for industrial use. At the Morcinek mine in southern Poland, coal is first dewatered to release the methane. Then a desalting unit (reverse-osmosis) converts up to 60 percent of the brine to fresh water, and methane from the coal is used to fuel an evaporator that further concentrates the brine.

Fresh water is a precious commodity in Eastern Europe, given the region's legacy of severely polluted ground water and streams. Commercialization of this process will provide potable water, and will provide an attractive alternative to deep-well injection.



Direct Fired Brine Evaporator, 50 cubic meters per day

Better technology tomorrow could let us recover methane from coal deposits in regions that are not economic today. For example, the Appalachian coal basin currently accounts for about two-thirds of the coal mine methane emissions in the United States—a rich potential resource.

Properly developing our coalbed methane resource can provide more clean energy, reduce our greenhouse gas contribution, and maintain a safe mining environment. The "miner's curse" that haunts every coal mine is becoming an asset.

FETC Point of Contact:

Charles W. Byrer

Project Manager/Geologist,
Fuels Resources Division

Office of Project Management

Phone: 304-285-4547

E-mail: cbyrer@fetc.doe.gov

Hugh D. Guthrie

Senior Management and
Technical Advisor

Office of Product Management for
Fuels and Speciality Markets

Phone: 304/285-4632

E-mail: hguthr@fetc.doe.gov

Charles A. Komar

Product Manager, Natural Gas
Supply and Storage

Office of Product Management for
Fuels and Specialty Markets

Phone: 304/285-4107

E-mail: ckomar@fetc.doe.gov

Contents

Next Article